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Report: System Efficiency of California's Electric Grid

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System Efficiency of California's Electric Grid

Policy and Planning Division

California Public Utilities Commission

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1.0 Summary Findings

In this report, we have examined how generation resource heat rates, electricity losses and equivalent forced outage rates of generation resources reflect the relative efficiency of electric generation and delivery in each California independently owned utilities (IOU) territory. Within these regions, we also compared distribution load factors to measure how well electric infrastructure capacity is being utilized. This effort resulted in a few key observations and suggestions regarding the use of system efficiency metrics to guide Commission decision-making on energy policy.

The initial finding is that Pacific Gas and Electric (PG&E) electricity losses were 85-100% higher than losses reported by Southern California (SCE) and San Diego Gas and Electric (SDG&E), which could be attributed to a number of factors including transmission infrastructure age, inclement weather, the distance between load centers and generation resources, or other technical issues such as operations and maintenance of high voltage transmission lines. Given the potential for yielding cost and reliability benefits for California IOUs and ratepayers, identification of the primary factors that have led to above-benchmark electricity losses (e.g. U.S. average) and the selection of technically and economically feasible solutions should be a high priority goal.

From 2006-2016, California IOU system load factors ranged from 52-62% whereas Sacramento Municipal Utilities District (SMUD) and Imperial Valley Irrigation District (IID) load factors ranged from 40-45%. As identified later in this report, load factor is the ratio of average and peak demand. Higher load factors that result from less peakier demand translates to a more efficient utilization of the electric grid. The result of this analysis indicates that a large portion of California's system capacity remains underutilized. While California embarks on a path to integrate utility-scale and distributed energy resources to meet policy, economic, and reliability goals, attention must also be paid to how efficiently electricity is delivered. Currently, the CPUC has been addressing how to potentially meet both challenges through the Integrated Distributed Energy Resources (IDER) and Renewable Portfolio Standard (RPS) proceedings via avoidance of transmission infrastructure costs. For example, the marginal impact of DERs and selection of energy-only versus fully deliverable RPS projects on system load factors could be utilized as a metric in these venues.

Based upon data obtained from the IOUs, distribution load factors had a range of 60-76%. Although this result was obtained from aggregated data, it generally reflects that IOU distribution infrastructure is utilized more efficiently than system infrastructure. This difference in capacity utilization could be used to decide whether to invest in distribution or transmission infrastructure and subsequently consider the tradeoff between procuring a number of distributed and aggregated resources versus utility-scale systems.

While the analysis presented herein provides a high-level overview of system efficiency and suggests that metrics can be used to guide Commission policy, caveats must also be observed with respect to comparing IOU performance. First, system efficiency is a reflection of a number of factors including demand forecasting, resource planning, and customer engagement in demand-side programs that differ in each IOU territory. With respect to demand forecasting, population growth and migration and temperature fluctuation are highly influential factors and at times difficult to predict. Consequently, resource planning that directs the procurement of system, local and flexible generation capacity resources, and transmission and distribution infrastructure, also reflects potential errors. Second, California IOU service territories reflect a diversity of climate zones, customers, and age of infrastructure. Therefore, an apples-to-apples comparison of the IOUs might be challenging. Third, the data and information obtained from disparate resources, including the California Energy Commission (CEC), US Energy Information Administration (EIA), the California IOUs, and the California Independent System Operator (CAISO) may not necessarily be temporally or geographically accurate or complete. In all instances, best attempts were made to procure and analyze the available data (i.e. matching of IOU and purchased power generation resources reported on an IOU's Federal Energy Regulatory Commission (FERC) Form 1 with the CEC's Quarterly Energy and Fuel Resource Database).

The equivalent forced outage rate (EFOR) for hydropower and gas turbine resources owned by California IOUs was reported to be roughly 5%. Given that EFOR data from plants that supply purchased power was not obtained, this result does not provide a measure of the reliability of this pool of resources. However, it is reasonable to assume that the frequency of downtime and derating of IOU versus independent power producer (IPP) owned generation resources is similar. During the next iteration of this report, assessment of the equivalent forced outage rate of demand (EFORd) for IOU and independent power producer (IPP) units, which accounts for plant downtime and capacity derating during demand periods, would provide a more robust measure of generation reliability.

Data analysis revealed that approximately 79-95% of 2015 net electricity generated by California IOU natural gas plants had heat rates at or below 10,000 BTU/kWh. This means that up to 95% of natural gas fired power generated came from resources more efficient than a natural gas peaker plant. Peaker plants are among the least efficient generation resources. Peaker plants represent 17.3% of natural gas-fired generators in California[1] and electricity is likely to be dispatched from these plants on high temperature days or when there are grid constraints (e.g. congestion in local capacity areas). As California continues to integrate supply and demand-side resources or programs that provide ramping capacity (e.g. energy storage) or shave peak load (e.g. aggregated demand response), assessing what portion of net electric generation continues to be sourced from less-efficient power plants, including peaker plants, could be a key metric to evaluate the cost-effectiveness of IOU programs.

[1] "Thermal Efficiency of Gas Fired Generation in California: 2015 Update" CEC, March 2016 p. 7 http://www.energy.ca.gov/2016publications/CEC-200-2016-002/CEC-200-2016-002.pdf

The details of how these results were obtained, including underlying assumptions, data sources, analytical methods, and assessments are included within the body of the report. As a final note, the findings are intended to provide a snapshot of current system efficiency conditions. In the future, as IOU supply-side and demand-side programs become more integrated, third-parties continue to be engaged in providing a suite of energy products and services, and retail choice gains more prominence, the status of system efficiency will continue to evolve.

2.0 Why is System Efficiency Important?

Electric grid or system efficiency can be defined as the efficiency of generation, transmission and distribution infrastructure and resources to reliably deliver electricity to end users when needed while maximizing use of system capacity and minimizing losses and costs.

The status of generation, transmission and distribution capacity efficiency has been measured via performance metrics including electric losses, system load factor, equivalent outage rates, and generation heat rates. This report will examine how these traditional metrics can be utilized to measure system efficiency levels for each of California's large independently owned utilities.

Given that electric grid resources and operations have begun to diversify on a larger scale, efforts are underway to ensure that generation, distribution, and transmission capacity can safely, reliably, and cost-effectively deliver electricity. For example, the CPUC has opened the Distributed Resources Plan (DRP) proceeding, R.14-08-013,[2] to identify optimal locations for the deployment of Distributed Energy Resources (DER). Elements of this proceeding will examine how Investor Owned Utilities (IOUs) plan to modernize the electric grid, including the procurement, installation and use of physical and virtual assets, including distribution automation and smart inverters, to enable a safe, reliable electric grid.

As generation, transmission and distribution capacity is procured and utilized to serve the needs of end users, it is also vitally important to gauge their impact on grid efficiency. In the context of this performance report, grid or system efficiency can be measured through metrics that identify:

- Electricity losses during transport and delivery;
- Energy intensity of electricity generation;[3]
- Frequency of forced outages of generation units;[4] and
- Transmission and distribution capacity utilization.

System efficiency data not only reflects the thermal efficiency of generation resources and the availability of grid capacity, but also reflects the influence of customer generation and consumption on the grid resources. This relationship has been highlighted in a 2015 report entitled "The Integrated Grid: Capacity and Energy in the Integrated Grid" released by the Electric Power Research Institute (EPRI).[5] Some of the key points from this report include:

- Peak system load is increasing at a faster rate than overall energy consumption;

[2] R.14-08-013, Order Instituting Rulemaking Regarding Policies, Procedures, and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769.

[3] Energy intensity of electricity production reflects the amount of thermal energy input (i.e. British Thermal Unit of natural gas) required to produce a kilowatt-hour (kWh) of electricity. Since California imports roughly 90 percent of its natural gas supply, we will not address the efficiency of natural gas extraction in this report. (Source: Supply and Demand of Natural Gas In California, California Energy Commission).http://www.energy.ca.gov/almanac/naturalgas_data/overview.html)

[4] Although generation resource forced outage rates traditionally reflect the status of generation reliability they also reflect the extent of generation downtime which impacts grid system efficiency.

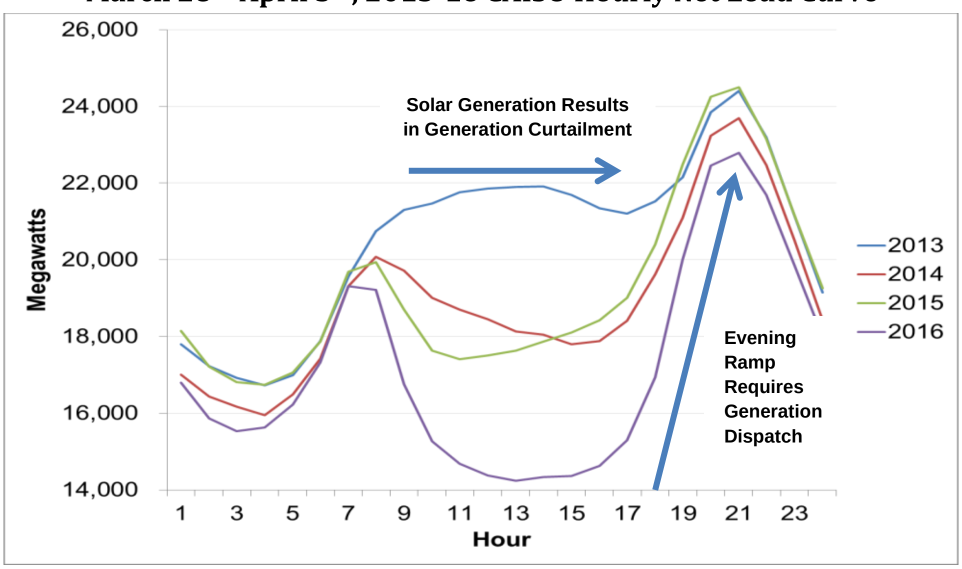
[5] 2015 The Integrated Grid: Capacity and Energy in the Integrated Grid", Electric Power Research Institute (EPRI). http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002006692

- Wind and solar energy can supply low or zero variable cost energy but alone are not firm sources of capacity; and
- While self-generation from rooftop solar systems can offset the need to obtain electricity from bulk power stations, as in a zero-net energy home, this may not reduce the need to obtain transmission and distribution capacity from a utility.

Given the findings of the EPRI report and that roughly 9,000 MW of self-generation capacity has been installed in California as of October 31, 2016,[6] determining optimal and efficient levels of transmission and distribution capacity will be increasingly important as distributed energy resources continue to interconnect to the grid.

In addition, as utility-scale renewable energy projects go online to satisfy Senate Bill (SB) 350[7] goals, achieving system efficiency will present a greater challenge. Figure 1 depicts the California Independent System Operator (CAISO) adjusted net load curve[8] from 2013-16 during late March to early April. As solar energy generation decreases the adjusted net load during the middle of the day, the CAISO may need to consider curtailing load from must-run, non-dispatchable generation resources. During the ensuing evening ramp, when generation resources must swiftly ramp up to meet peak load needs, the CAISO must dispatch fast ramping peaker plants or other supply-side resources (e.g. energy storage devices) or demand-side resources (e.g. demand response) to rapidly address maximum load conditions. In both instances, engaging in generation curtailment during minimum load conditions or generation dispatch during fast ramp periods will test the ability of system planners and operators to attain system efficiency.

Figure 1
March 28th-April 3rd, 2013-16 CAISO Hourly Net Load Curve



[6] California Energy Commission –Renewable Energy Overview
http://www.energy.ca.gov/renewables/tracking_progress/documents/renewable.pdf
[7] Senate Bill 350 was enacted in 2015 to set a goal for reducing California greenhouse gas emissions (GHG) to 40% below 1990 levels by 2030. A number measures were highlighted to meet this target including doubling investment in energy efficiency, electrifying transportation, increasing the percentage of renewables in California's generation portfolio to 50% by 2030, and integrated resource planning.
[8] Adjusted net load is the difference between electric generation, including renewable generation, and customer load.

3.0 System Efficiency Metrics

In the prior section, the importance of system efficiency was highlighted. System efficiency can be measured through a variety of metrics including:

- ***Electricity losses -*** the amount of electricity lost through heat as it is delivered through transmission and distribution lines to end users.
- ***Electric transmission and distribution system load factors*** - the ratio of the average electric system load and the average system peak load. This statistic is a measure of capacity utilization of the transmission and distribution networks.
- ***Equivalent forced outage rate*** - the frequency of forced outages of generation resources is a measure of generation reliability but also impacts system efficiency.
- ***Heat rate*** - the amount of fuel energy input required to produce a unit of electricity. This value is a proxy for the efficiency of generation resource capacity.

Electricity Losses

According to the U.S. Energy Information Administration (EIA), approximately 6% of the electricity that is transmitted and distributed annually in the United States (US) is lost while it is delivered for end use consumption (Table 1).[9] Electricity losses in the California grid are comparable to the 6% nationwide average but have decreased from a value of 7.95% to 6.58% from 2009 to 2014.

Table 1
Estimated Electricity Losses from Delivery in California (2009-14)

Supply and disposition of electricity, 2009 through 2014
California
megawatthours

Category	2014	2013	2012	2011	2010	2009
Supply						
Generation						
Electric utilities	71,037,135	78,407,643	82,486,064	105,360,204	96,939,535	85,123,706
Independent power producers	89,576,573	86,201,998	80,574,100	58,255,052	69,294,065	80,766,990
Combined heat and power, electric	20,207,580	16,905,498	18,163,487	18,656,710	19,582,003	21,008,878
Electric power sector generation subtotal	**180,821,288**	**181,515,139**	**181,223,651**	**182,271,967**	**185,815,603**	**186,899,573**
Combined heat and power, commercial	2,802,160	2,761,572	2,894,426	2,880,277	2,300,044	2,243,754
Combined heat and power, industrial	15,184,174	15,800,404	15,400,490	15,652,598	16,009,948	15,632,805
Industrial and commercial generation subtotal	**17,986,334**	**18,561,976**	**18,294,916**	**18,532,875**	**18,309,992**	**17,876,559**
Total net generation	**198,807,622**	**200,077,115**	**199,518,567**	**200,804,842**	**204,125,596**	**204,776,132**
Total international imports	**12,369,304**	**12,414,327**	**8,572,815**	**6,269,511**	**3,473,583**	**3,047,148**
Total supply	**211,176,926**	**212,491,442**	**208,091,382**	**207,074,353**	**207,599,179**	**207,823,280**
Estimated losses	**13,887,284**	**14,243,546**	**14,288,222**	**16,408,719**	**15,972,943**	**16,524,105**
Percentage losses	**6.58%**	**6.70%**	**6.87%**	**7.92%**	**7.69%**	**7.95%**

Facility direct retail sales are electricity sales from non utility power producers which reported electricity sales to a retail customer.
Net interstate trade = Total supply - (total electric industry retail sales + direct use + total international exports (if applies) + estimated losses).
Net trade index is the sum of total supply / (total disposition - net intersde).
A negative net interstate trade value indicates a net import of electric power.
Notes: Totals may not equal sum of components because of independent rounding. Estimated losses are reported at the utility level, and then allocated to states based on the utility`s retail sales by state. Reported losses may include electricity unaccounted for by the utility. Direccommercial or industrial use of

Table 2 depicts electricity losses reported by Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Electric (SDG&E) on 2015 FERC Form 1s. In order to calculate percent electricity losses, total energy losses were divided by total sales.[10] While the aggregated California IOU data indicate that roughly 6% of electricity is lost, PG&E's electricity losses (8.66%) are approximately twice that of SCE and SDG&E (respectively 4.26% and 4.66%).

[9] U.S. Energy Information Administration, Frequently Asked Questions.
[10] Ideally, electricity produced by self-generation should be subtracted from total sales when used to calculate electricity losses. However, this data was not readily accessible.

Table 2
Electricity Losses Reported by California IOUs (2015)[11]

	PG&E	SCE	SDG&E	Total
Sales to Customers (MWh)	86,167,420	74,929,346	16,267,013	177,363,779
Sales for Resale (MWh)	1,813,603	4,031,926	16,865,020	22,710,549
Energy Used By Company (MWh)	NA	134,341	32,899	167,240
Total Sales (MWh)	87,981,023	78,961,272	33,132,033	200,074,328
Total Energy Losses (MWh)	7,615,777	3,360,028	1,544,260	12,520,065
Percent Electricity Loss	**8.66%**	**4.26%**	**4.66%**	**6.26%**

Given that electric line loss, a primary contributor to electric losses, is a function of the distance required to deliver electricity from generation resources to load centers, it is conceivable that PG&E's relatively higher level of electricity losses is attributed to this factor. However, there are a host of factors that increase electricity line loss including physical factors (i.e. high temperature, wind and rain)[12] and physical infrastructure factors (e.g. the age and condition of transmission lines).[13]

Figure 2
California and US Utility Percent Electric Losses (2015)

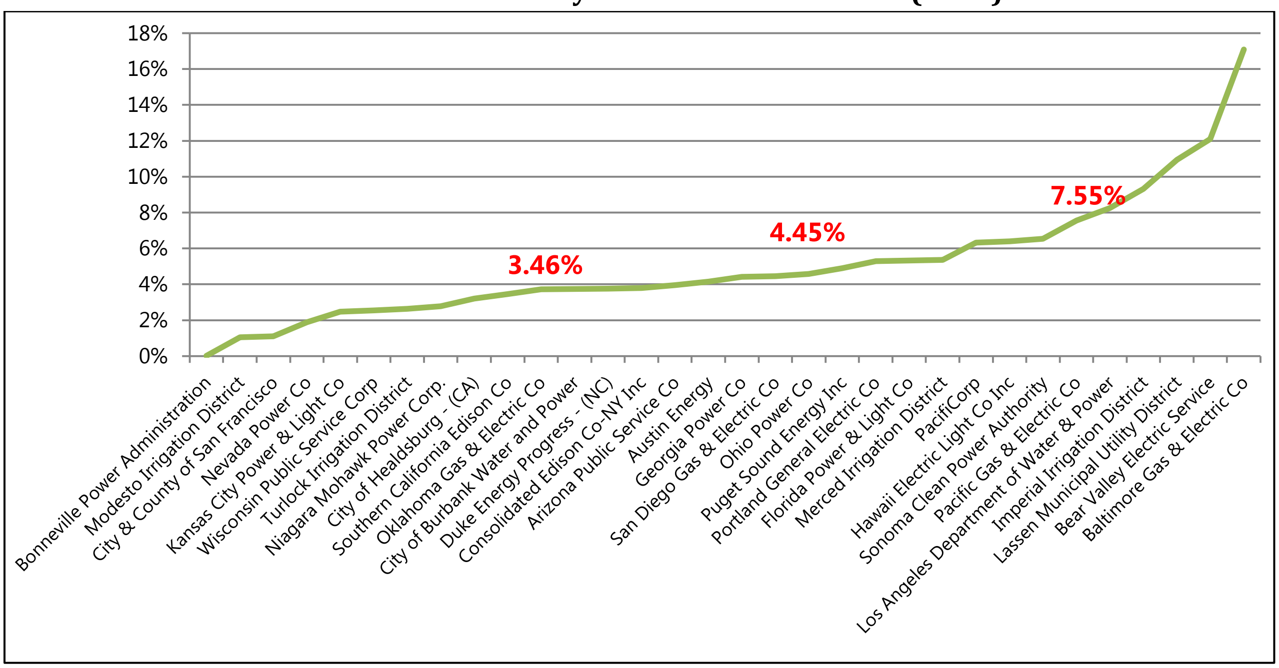


Figure 2 depicts percent electricity losses, expressed as the ratio of electricity losses and electricity disposed or delivered, for a select group of U.S. electric utilities. The data utilized to calculate these values

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[11] PG&E, SCE and SDG&E Form 1.
[12] Wong, L. California Energy Commission Staff Paper: "A Review of Transmission Losses in Planning Studies", August 2011, p.9.
[13] Id p.18

was obtained from Form EIA-861.[14] While the percent electricity losses as derived from Form FERC 1 and EIA-861 data are not comparable on an absolute basis, due potentially to methodological differences regarding how electricity losses are calculated, a comparative assessment between values reported in Table 2 and Figure 2 indicate that PG&E's percent electricity losses are noticeably higher.

System Load Factors

Another metric that can be used to assess system efficiency is the system load factor (load factor), or the ratio of the annual average system load (average load) and the annual peak system load (peak load). The ratio of the average load and the peak load is a representation of the capacity utilization of California's electric grid. A higher system load factor indicates a higher degree of capacity utilization.

Table 3
Annual System Load in the CAISO Balancing Authority: 2011 to 2015[15]

Year	Annual total energy (GWh)	Average load (MW)	% change	Annual peak load (MW)	% change
2011	226,087	25,791	0.4%	45,545	-3.8%
2012	234,584	26,740	3.7%	46,847	2.9%
2013	231,800	26,461	-1.0%	45,097	-3.7%
2014	231,610	26,440	-0.1%	45,090	0.0%
2015	231,495	26,426	0.0%	47,257	4.8%

Table 3 details the 2011-2015 average and peak loads in CAISO's balancing authority that includes PG&E's, SCE's and SDG&E's service territories. As indicated in Table 3, the average load declined from 2011-15 whereas the % change in peak load fluctuated from -3.8% to +4.8%. This variation is likely attributed to the rise and fall of summer peak temperatures and the subsequent impact on air conditioning loads.

Table 4 reflects 2011-15 system load factors, which range from 56% to 59%. These values were derived by dividing the average load and the peak load values contained in Table 3. Based upon the minimal year-to-year change in average load from 2013-2015, system load factor in recent years has primarily been influenced by annual shifts in peak load.

[14] Energy Information Administration (EIA), Form EIA-861, Electric power sales, revenue, and energy efficiency https://www.eia.gov/electricity/data/eia861/

[15] California Independent System Operator, 2015 Annual Report on Market Issues & Performance at 26.

Table 4
Annual System Load Factor in the CAISO Balancing Authority: 2011 to 2015

Year	Average load (MW)	Peak Load (MW)	System load factor (%)	% Change
2011	25,791	45,545	56.6%	
2012	26,740	46,847	57.1%	0.798%
2013	26,461	45,097	58.7%	2.797%
2014	26,440	45,090	58.6%	-0.064%
2015	26,426	47,257	55.9%	-4.636%

Figures 3-5 depict 2006-2016 net peak demand[16] and load factors in PG&E, SCE and SDG&E planning areas as reported in the 2016 California Energy Commission (CEC) Mid Case Final Baseline Demand Forecast. During this time period, PG&E's annual load factor declined from 63% to 58% whereas SCE's and SDG&E's load factors respectively fluctuated roughly between 52% to 57% and 50% to 58%. Generally, the 2011-15 PG&E data parallels the CAISO system load factor data presented in Table 4.

Notably, there is no consistent increasing or decreasing trend in PG&E and SCE load factors. While PG&E's and SDG&E's net peak demand and load factors reflect a high negative correlation, respectively -0.97 and -0.88, SCE's net peak demand and load factors reflect a moderate negative correlation, -0.65. Essentially, this result indicates that as utility peak loads rise, utility load factors and system capacity utilization decreases. Conversely, as average load increases, load factors and system capacity utilization increase. This relationship can be visualized in the following load factor equation:

$$\text{Load factor} \uparrow = \frac{\text{Average load} \uparrow}{\text{Peak load} \downarrow}$$

There are a few conclusions that can be made in reference to the data trends. SCE's 2006-16 load factors may be more heavily influenced by average load, given their moderate correlation with net peak demand. Scenarios that impact average load can include population growth or the degree of time-independent plug load (e.g. refrigeration or air conditioning load that exists before and after peak hours due to extended periods of high temperature) in a utility service territory. On a statewide basis, load factor trends may have been also influenced by population movement to and growth in the Central Valley and increased air conditioning (A/C) load in coastal regions.[17]

[16] CEC defines Net Peak Demand as the total end use load plus losses minus self-generation.
[17] Personal communication with CEC staff

Figure 3
2006-16 PG&E Net Peak Demand and Load Factors[18]

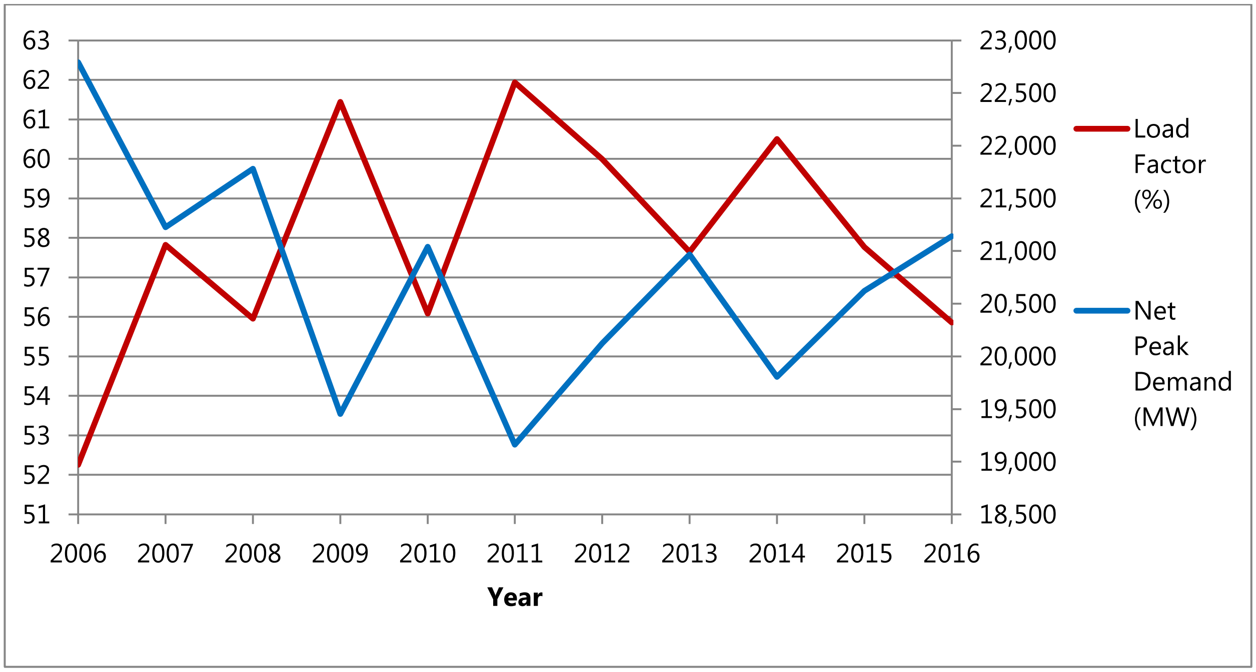
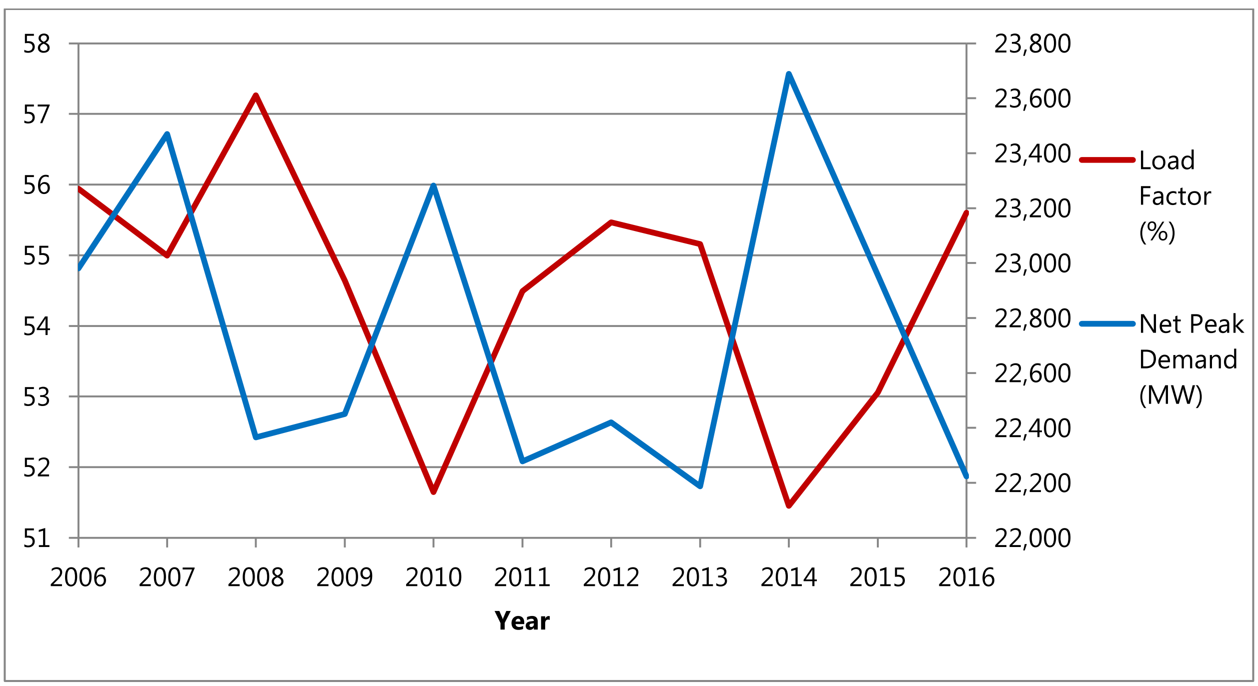


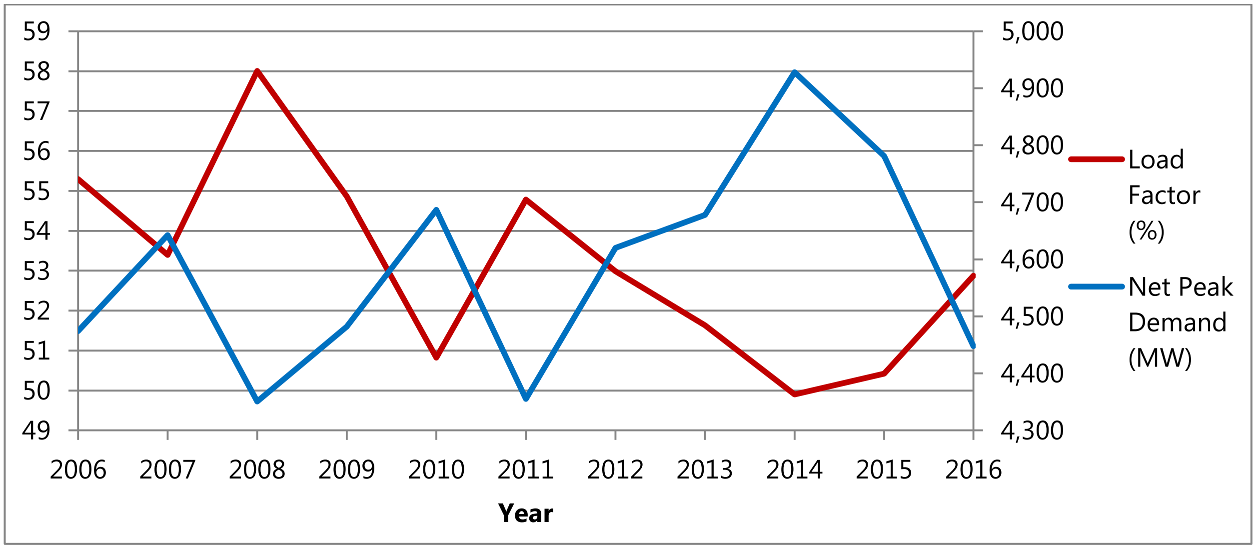
Figure 4
2006-16 SCE Net Peak Demand and Load Factors[19]



[18] California Energy Commission (CEC), California Energy Demand, Updated Forecast, 2017-27, PG&E Mid Case Final Baseline Demand Forecast http://www.energy.ca.gov/2016_energypolicy/documents/

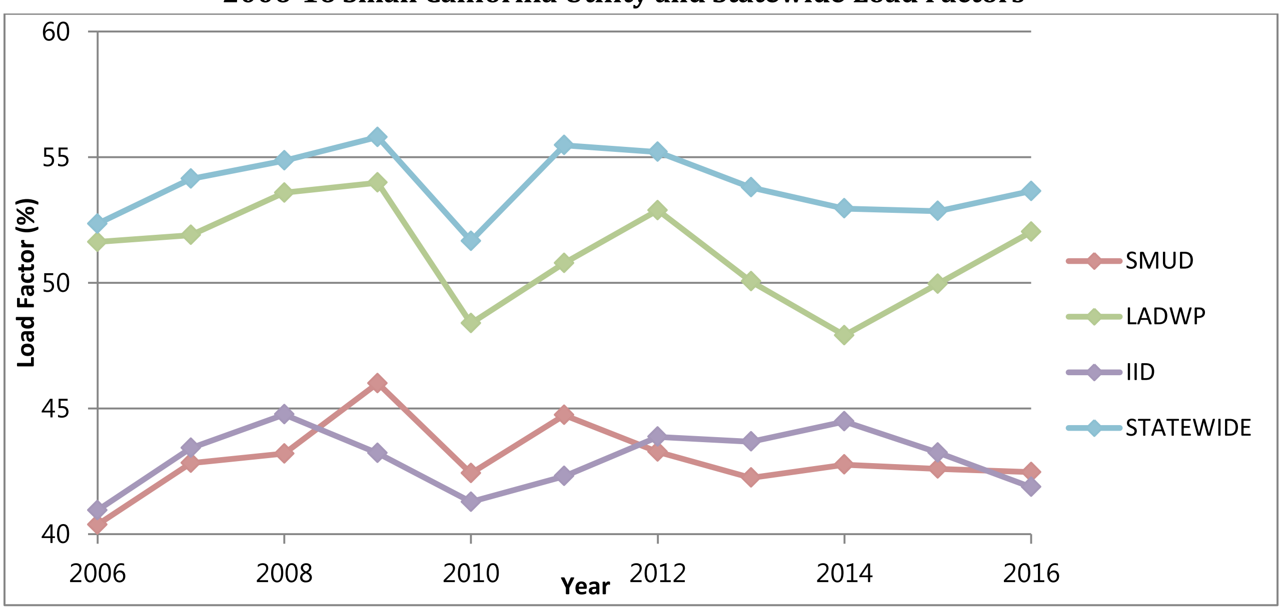
[19] California Energy Commission, California Energy Demand, Updated Forecast, 2017-27, SCE Mid Case Final Baseline Demand Forecast http://www.energy.ca.gov/2016_energypolicy/documents/

Figure 5
2006-16 SDG&E Net Peak Demand and Load Factors[20]



In comparison with reported PG&E, SCE and SDG&E data, Sacramento Municipal Utility District (SMUD) and the Imperial Valley Irrigation District (IID) had load factors in the range of 40-46%. It is conceivable that SMUD and IID customers reside in climate zones where there is a high degree of temperature fluctuation between seasons, higher summer temperatures and more homogenous climate zones, which may lead to peakier energy use (i.e. use of A/C units) leading to lower load factors.

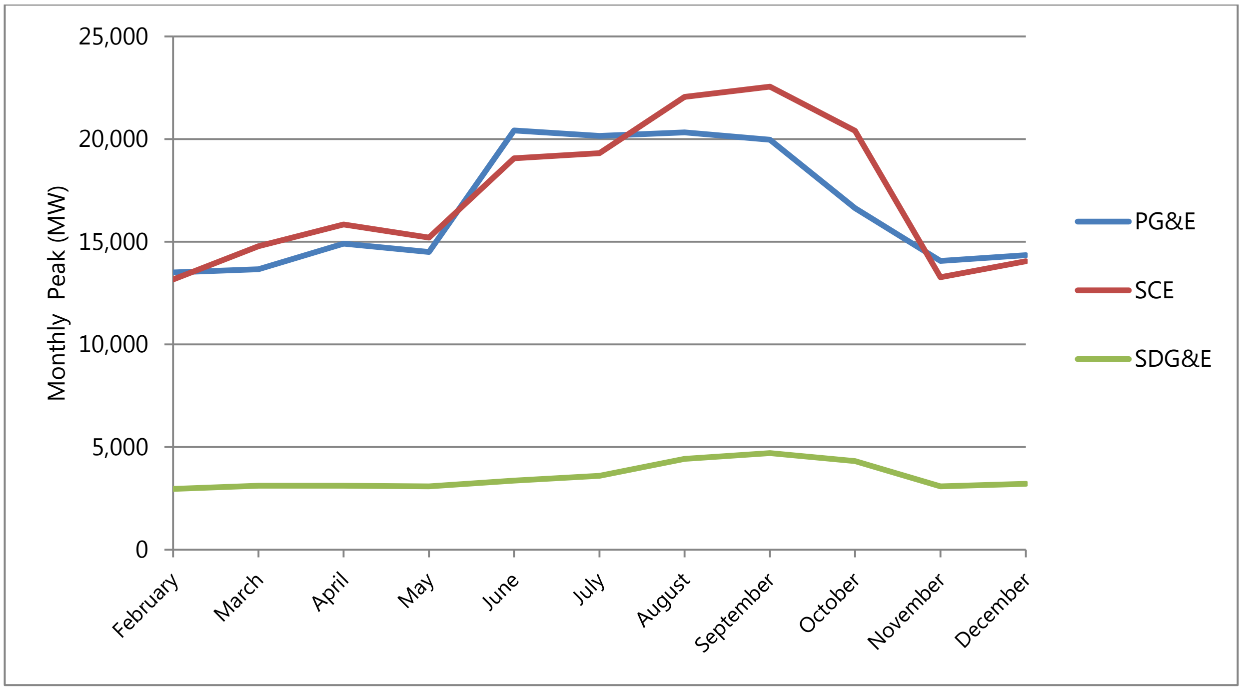
Figure 6
2006-16 Small California Utility and Statewide Load Factors[21]



[20] California Energy Commission, California Energy Demand, Updated Forecast, 2017-27, SDG&E Mid Case Final Baseline Demand Forecast http://www.energy.ca.gov/2016_energypolicy/documents/
[21] California Energy Commission, California Energy Demand, Updated Forecast, 2017-27, SMUD Mid Case Final Baseline Demand Forecast http://www.energy.ca.gov/2016_energypolicy/documents/

On a seasonal basis, peak loads are variable within each California IOU territory. According to CAISO, 41% of the annual peak load is centered in the Los Angeles Basin while the Greater San Francisco Bay Area contributes 21 percent of peak load.[22] Temporal variation in monthly system peaks within each major California IOU service territory is also not coincident. As depicted in Figure 7, PG&E's highest monthly peak load in 2015 occurred in June whereas SCE's and SDG&E's highest monthly peak loads occurred in September. In addition, SCE and SDG&E monthly peak loads steeply increase as the summer season progresses, mostly likely in relationship to higher temperatures and increased A/C load. Consequently, 2015 summer load factors in SCE's and SDG&E's service territory were likely lower than in PG&E's service territory.

Figure 7
2015 PG&E, SCE, SDG&E Monthly Peak Load [23]



Aside from differences attributed to geographic location and season, monthly peak load also varies according to time of day. Figures 8-10 respectively depict PG&E's, SCE's and SDG&E's 2015 monthly peak load profiles in relationship to when these peaks occur. While PG&E's summer peak loads are generally in the range of 20,000 MW and occur at 1800 hours, SCE's and SDG&E's 2015 summer peak loads had significant variation and occurred earlier in the day. In SCE's case, peak load was reached between 1500 and 1700 hours while SDG&E's occurred between 1200 and 1500 hours. From a system planning perspective, wide variations in monthly peak periods can impact the efficiency of deploying supply-side resources that provide generation capacity (i.e. natural gas peaker plants) or designing and implementing demand-side programs (e.g. dispatch of A/C cycling demand response).

[22] California Independent System Operator, 2015 Annual Report on Market Issues & Performance at 27.
[23] 2015 PG&E, SCE, SDG&E Federal Energy Regulatory Commission Form 1, p. 401b

Figure 8
2015 PG&E Monthly Peak Loads According to Hour [24]

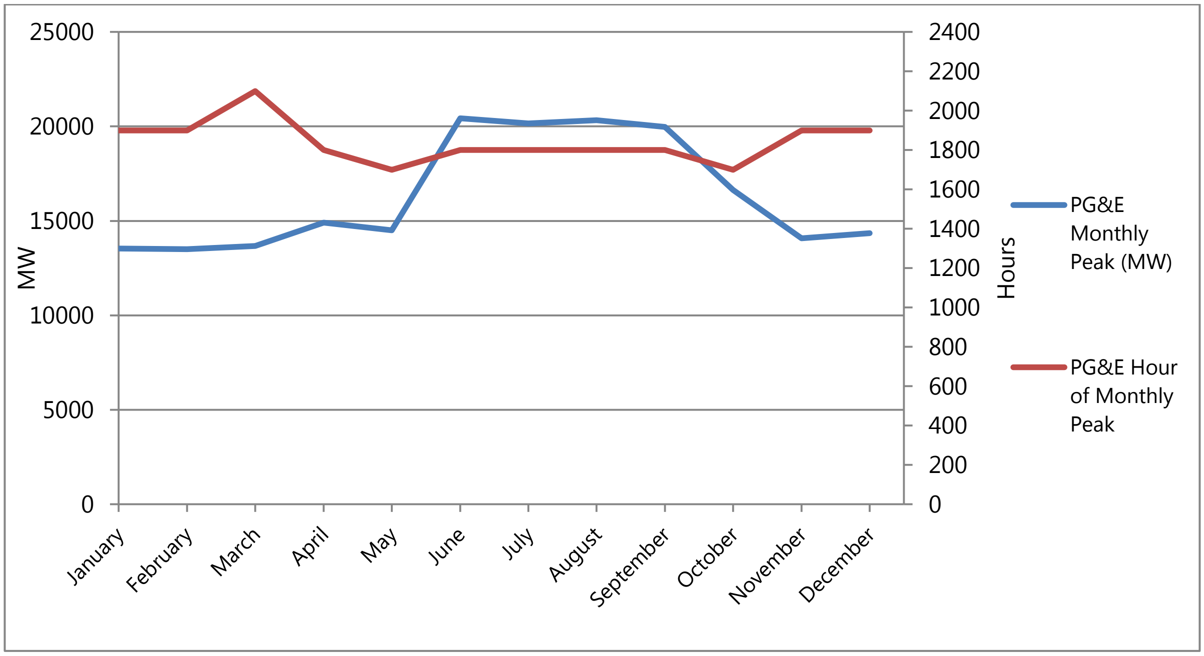
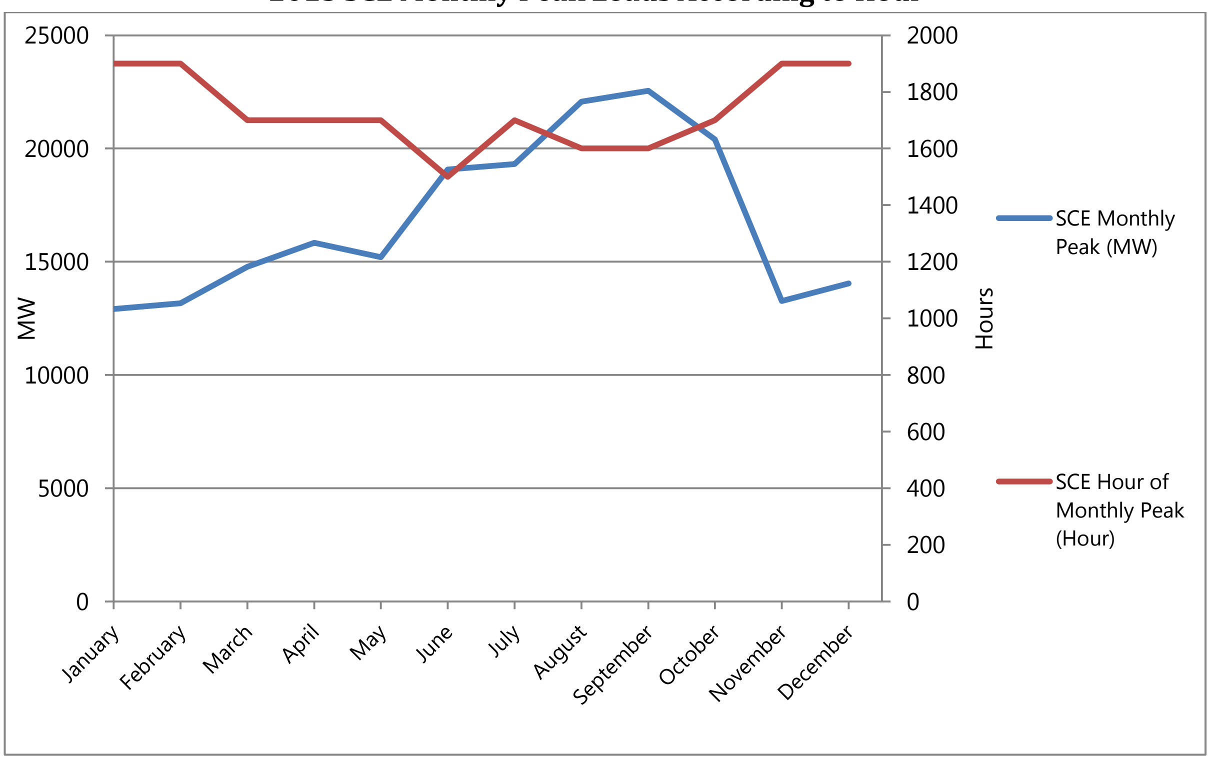
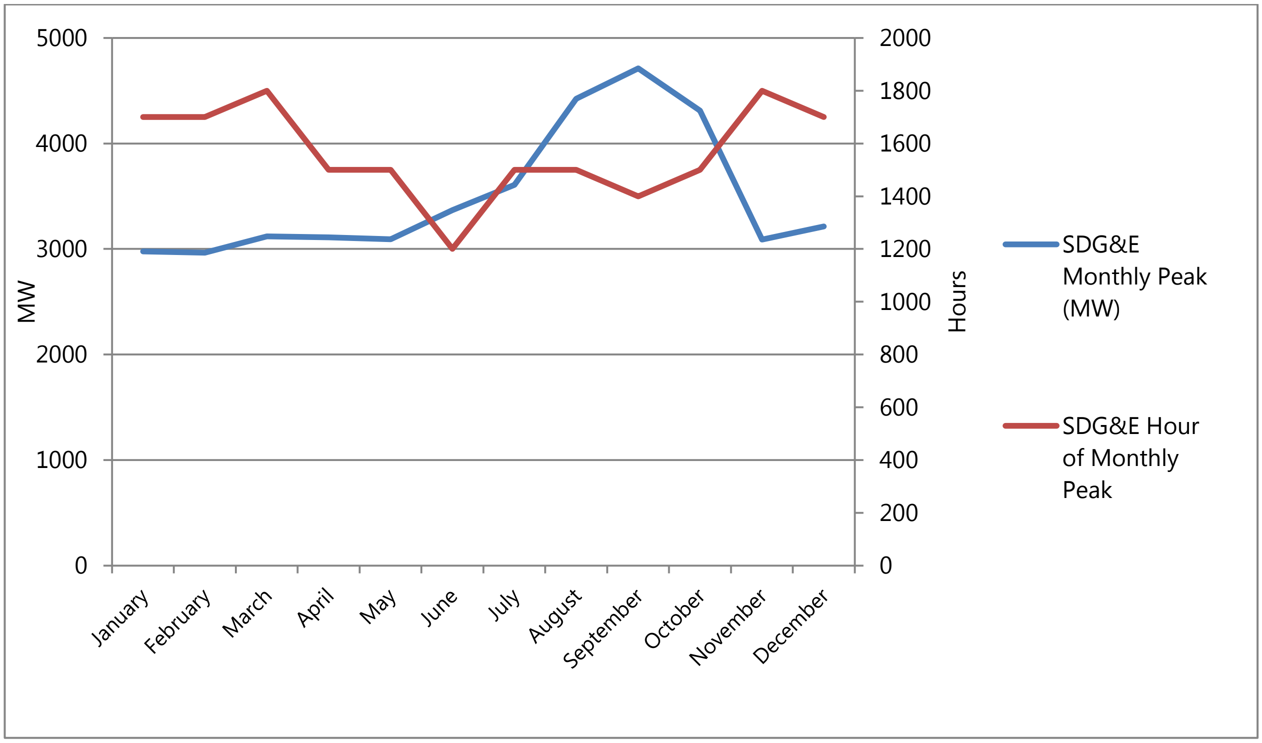


Figure 9
2015 SCE Monthly Peak Loads According to Hour[25]



[24] 2015 PG&E Federal Energy Regulatory Commission Form 1, p. 401b
[25] 2015 SCE Federal Energy Regulatory Commission Form 1, p. 401b

Figure 10
2015 SDG&E Monthly Peak Load According to Hour[26]



Distribution Circuit Load Factor

Figures 11-13 depict 2012 and 2016 monthly frequency distributions for California large IOU distribution circuit load factors.[27] The frequency distributions describe how often a utility's distribution circuits have a specific range of load factors within a year.[28] As stated earlier, load factor is expressed as the ratio of average load and peak load and is a measure of the capacity utilization of distribution circuit components including substations, feeders, and transformers.

Based upon a review of data provided by the IOUs, PG&E distribution circuits most often had monthly load factors in the range of 70% in 2012 and 2016 (Figure 11) while SCE had values in the range of 80% (Figure 12) and SDG&E had values that decreased from 80% in 2016 to 75% in 2012. Approximately 81% of PG&E's 2016 monthly load factors ranged from 60-80%, 76% of SCE's 2016 monthly load factors ranged from 70-80%, and 79% of SDG&E's 2016 monthly load factors ranged from 75-85%. Generally, the aggregated data indicates that PG&E distribution circuits had a higher frequency of lower monthly load factors than those in SCE and SDG&E service territories.

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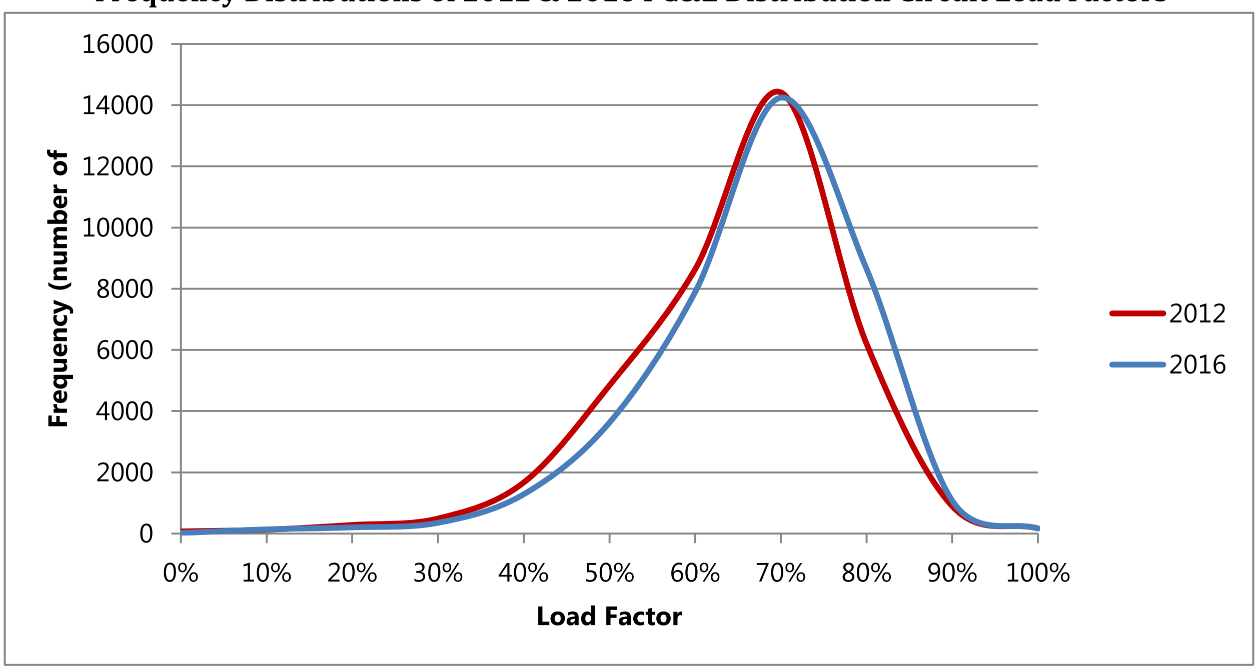
[26] 2015 SDG&E Federal Energy Regulatory Commission Form 1, p. 401b
[27] Distribution circuit load factor is defined as the monthly average load divided by the monthly peak load for a distribution circuit.
[28] Load factor data was provided by PG&E, SCE, and SDG&E via data request. Note that PG&E's did not provide data for October-December 2016. After the data was obtained, frequency distributions for distribution circuit load factors were developed by creating load factor

While the frequency distributions illustrate the occurrence of monthly load factor ranges, Table 5 presents average, median, and standard deviation values. The average monthly distribution load factor for PG&E in 2012 increased from 60% to 62% in 2016, while SCE's average load factor increased from 66% to 70% and SDG&E's average load factor decreased from 78% to 76% during this period. Note that the average load factor estimates capture the occurrence of both low and high load factors at the tail ends of the frequency distributions. However, these statistics don't capture the characteristics of distribution circuits that may have low load factors (e. g. a greater portion of residential versus commercial customers that have peakier load profiles) or that have high load factors even during peak load periods. Further analysis could identify and prioritize distribution circuit scenarios where load management efforts should be focused.

Aside from examining average values, variability in the monthly load factors can be represented by the standard deviation.[29] According to the data, SDG&E's distribution load factor data is less variable (i.e. the distribution load factor data respectively had standard deviations of 7% and 9% during 2012 and 2016) when compared to PG&E's data (standard deviations of 13% in 2012 and 2016) and SCE's data (respective standard deviations of 23% in 2012 and 16% in 2016) which likely includes values from newer circuits that either have not begun or just initiated electric service. This result indicates that SDG&E's frequency distribution of monthly load factors is less disperse and reflects a higher frequency of values in the 75-85% range. PG&E's data is more disperse and features a higher frequency of values in the 60-80% range. As stated earlier, this could be attributed to differences in California IOU circuit diversity, climate zones and other factors.

Figure 11
Frequency Distributions of 2012 & 2016 PG&E Distribution Circuit Load Factors



[29] The standard deviation is a measure of data dispersion and is equal to the square root of the mean of the squares of the deviations from the arithmetic mean of the distribution.

Figure 12
Frequency Distributions of 2012 & 2016 SCE Distribution Circuit Load Factors

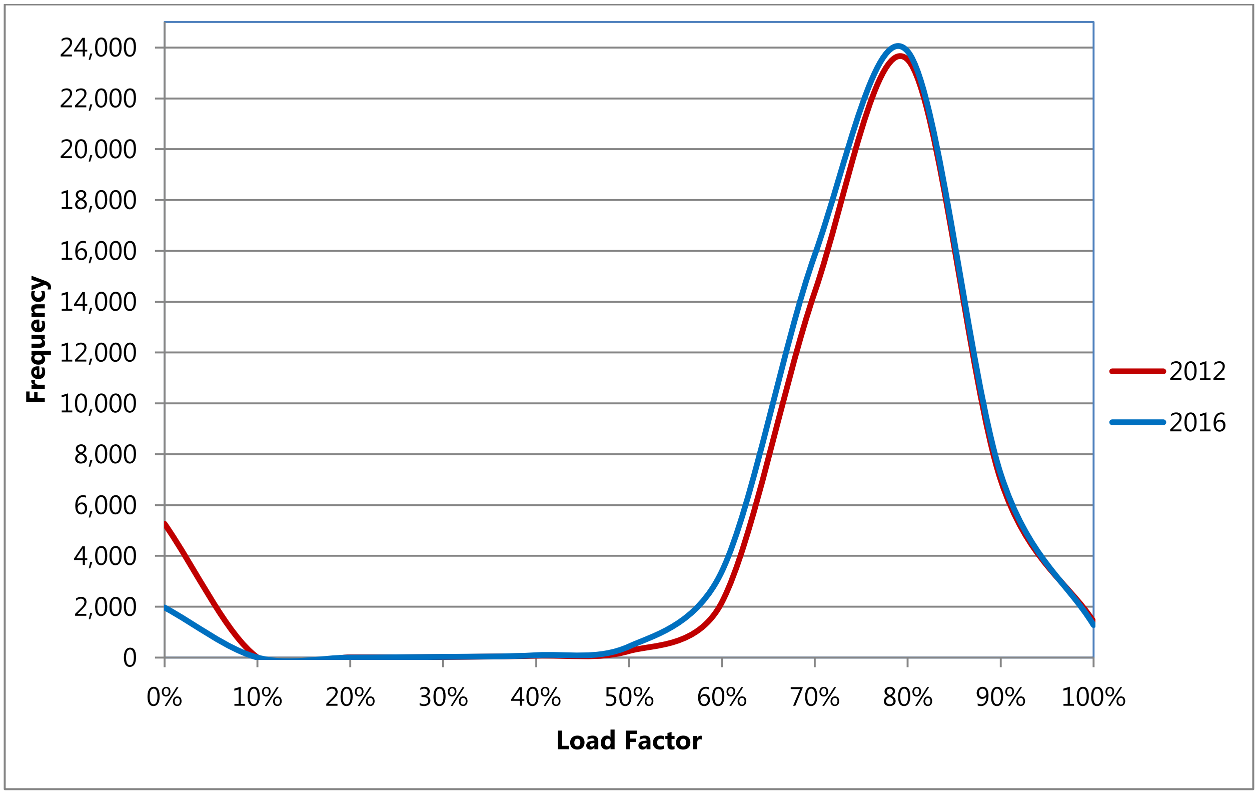


Figure 13
Frequency Distributions of 2012 and 2016 SDG&E Distribution Circuit Load Factors

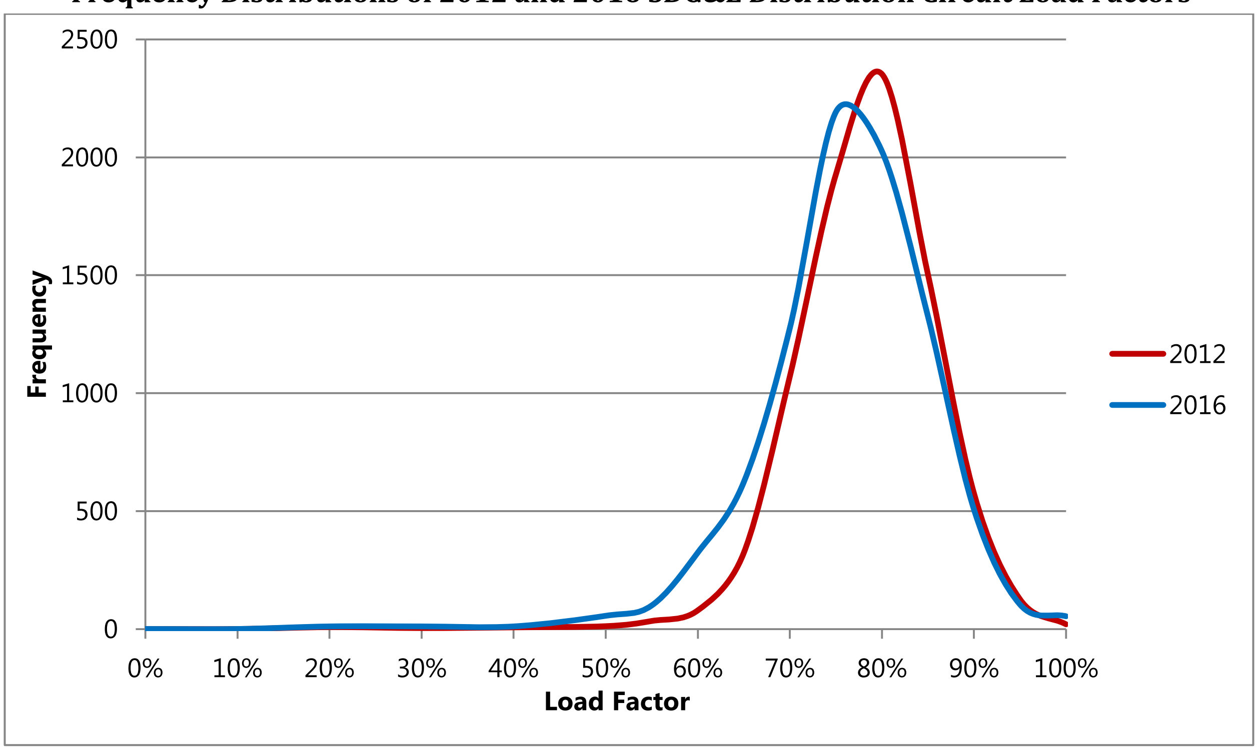


Table 5
Average and Standard Deviations of California IOU Distribution Circuit Load Factors

California IOU	PG&E	SCE	SDG&E
Average			
2012	60%	66%	76%
2016	62%	70%	74%
Median			
2012	62%	72%	76%
2016	64%	72%	75%
Standard Deviation			
2012	13%	23%	7%
2016	13%	16%	9%

Equivalent Forced Outage Rate

The availability of generation resources to supply electricity when needed is a factor that impacts system efficiency. If generation resources are not available to supply generation capacity, essentially during peak demand periods, additional resources must be procured to provide replacement power. While the CPUC's resource adequacy (RA) program ensures that an incremental generation reserve margin of 15% is procured to ensure generation reliability,[30] increasing the uptime of California's generation fleet is crucial to optimizing RA procurement targets thereby maximizing the RA program's effectiveness.

One measure of generation resource uptime is the equivalent forced outage rate (EFOR).[31] The EFOR reflects the portion of time that a generation resource is removed from service (outage) or reduced in service (derating) due to an emergency or unanticipated component failure.[32] Based upon requirements outlined in Federal Energy Regulatory Commission (FERC) Order 693, EFOR data is provided annually by operators of electric generation facilities greater than 20 MW to the North American Electric Reliability Corporation (NERC).

Table 6 depicts 2015 EFOR data reported to NERC by 7,700 generating units in North America. Note that EFORs for nuclear generation (3.38%-6.27%) are generally much lower than EFORs for gas turbine generators (39.68%-57.01%). In addition, small capacity resources (i.e. ≤ 30 MW) have relatively higher EFOR values.

Figure 14 illustrates the range of EFORs for generation sources owned by PG&E, SCE and SDG&E in comparison EFORs for North American generation resources. The California IOU EFOR dataset does not include EFOR values for purchased power and is aggregated to preserve data confidentiality. In addition, the dataset does not reflect the range in EFOR values based upon capacity size.

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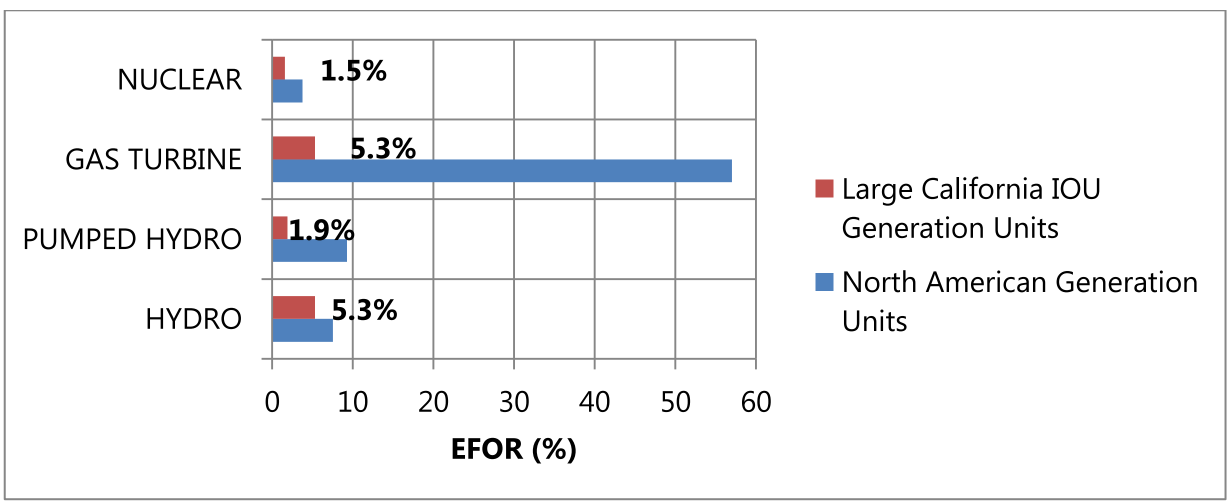
[30] California Public Utilities Commission, Resource Adequacy Program http://cpuc.ca.gov/RA/
[31] EFOR = ((Forced Outage Hours) + (Equivalent Forced (Unplanned) Derated Hours))/ (Forced Outage Hours) + (Service Hours)+ (Equivalent Reserve Shutdown Forced Derated Hours) as defined in North American Electric Reliability Corporation, Generating Availability Reporting System, Appendix F – Performance Indexes and Equations http://www.nerc.com/pa/RAPA/gads/DataReportingInstructions/Appendix_F%20-%20Equations.pdf
[32] Glossary of Terms Used in NERC Reliability Standards http://www.nerc.com/files/glossary_of_terms.pdf

Based upon the data provided, the EFOR values for PG&E, SCE and SDG&E nuclear generators, gas turbines, and hydropower and pumped hydropower generators fall well below the values for North American generation units, except for hydro resources. While this data does not reflect EFORs for purchased power, it does provide an indicator that forced outages and deratings may not significantly impact generation reliability. However, as California's generation portfolio features the interconnection of greater numbers of smaller capacity generation units, that have relatively higher EFORs, the potential for their impact on future generation reliability should be examined.

Table 6
2015 EFOR Values for North American Generation Resources[33]

	Capacity (MW)	EFOR (%)
HYDRO	All Sizes	7.56
	1-29	12.18
	30+	4.05
PUMPED HYDRO	All Sizes	9.29
GAS TURBINE	All Sizes	57.01
	1-19	89.25
	20-49	77.65
	50+	39.68
NUCLEAR All Types	All Sizes	3.78
	400-799	6.27
	800-999	3.41
	1000 +	3.38

Figure 14
Comparison of EFOR Values for Large California IOU and North American Generation Resources [34]



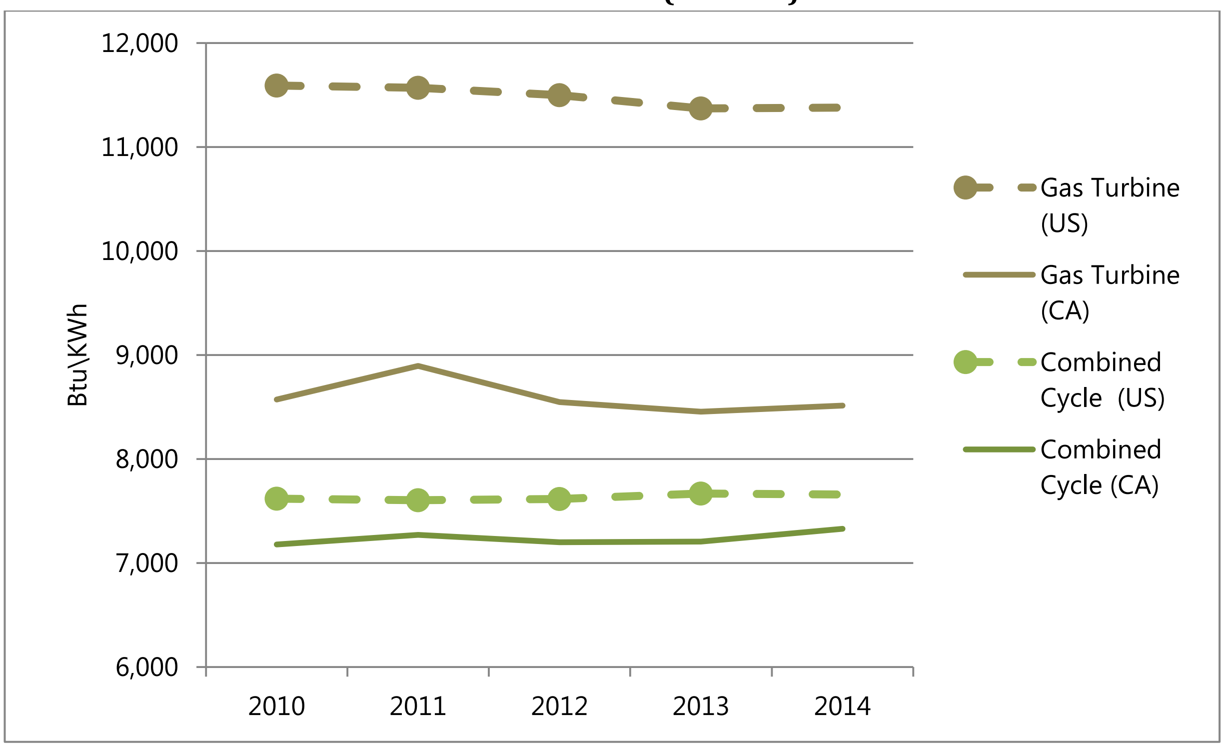
[33] North American Electric Reliability Corporation, Generating Availability Reporting System, 2015 Generating Unit Statistical Brochure.
[34] 2015 SDG&E Federal Energy Regulatory Commission Form 1, p. 401b

Generation Resource Heat Rates

An additional measure of system efficiency is a generation portfolio's heat rate or thermal efficiency. Heat rate is typically expressed as the ratio of British Thermal Units (Btu) consumed and the kilowatt or megawatt electricity hours (kWh or MWh) generated by fossil fuel or nuclear power plants. As the generation portfolio's heat rate decreases electricity is produced more efficiently.

One method of characterizing system heat rate is to examine the average heat rates of specific types of thermal generation resources. Figure 15 compares the heat rates of US versus California natural gas turbine and combined cycle generators. While the efficiency of combined cycle generators in the US and CA is relatively similar, the California natural gas generation fleet has a lower heat rate (~8,500-9,500 Btu/kWh) in comparison to the US fleet (~11,500 Btu/kWh).[35]

Figure 15
Gas Turbine and Combined Cycle Generator Heat Rates
US versus California (2010-15)[36] [37]



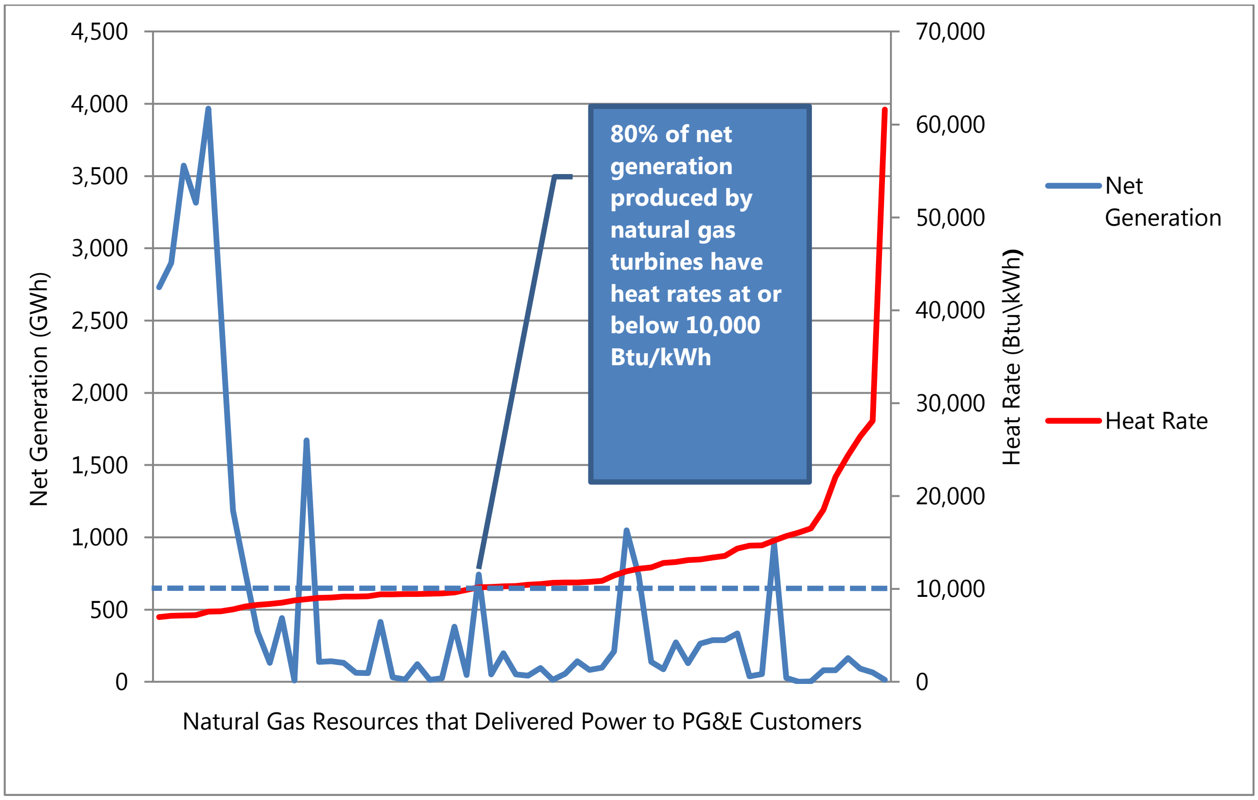
Figures 16-18 depict the heat rates of California natural gas generators that supplied electricity to PG&E, SCE and SDG&E in 2015. These profiles are intended to provide a general representation of thermal generator efficiency in relationship to net electricity generation in each California IOU service territory. In order to create the profiles, generation resources listed on 2015 PG&E, SCE and SDG&E Form 1 reports,

[35] "A combined cycle generation unit consists of one or more combustion turbines and one or more boilers with a portion of the required energy input to the boilers provided by the exhaust gas of the combustion turbine." EIA Glossary https://www.eia.gov/tools/glossary/index.cfm?id=C
[36] US Energy Information Agency, Table 8.2 Average Tested Heat Rates by Prime Mover and Energy Source
[37] Thermal Efficiency of Gas-Fired Generation in California: 2015 Update http://www.energy.ca.gov/2016publications/CEC-200-2016-002/CEC-200-2016-002.pdf

including utility or independent power producer (IPP) owned resources, were matched with those reported in the 2015 CEC Quarterly Fuel and Energy Report (QFER) database. The heat rates and net electricity generated by these matched resources were then plotted.

Based upon a review of the data, approximately 80 % of PG&E's 2015 net electric generation produced by natural gas turbines had heat rates at or below 10,000 Btu/kWh, which represents the 2014 value for a peaker plant in California.[38] Comparatively, 79 % of SCE's and 95 % of SDG&E's 2015 net electric generation were respectively supplied by generation resources with heat rates at or below this value. These results indicate that a large portion of net electric generation in each California IOU service territory is supplied by thermally efficient generators.

Figure 16
2015 PG&E Natural Gas Resource Heat Rates and Net Generation [39] [40]



[38] "Thermal Efficiency of Gas Fired Generation in California: 2015 Update" CEC, March 2016 http://www.energy.ca.gov/2016publications/CEC-200-2016-002/CEC-200-2016-002.pdf
[39] This data includes net generation and heat rates from natural gas generation resources, including PG&E owned and third-party resources that supply purchased power."

[40] Data obtained from PG&E Form 1 and California Energy Commission, Quarterly Fuel and Energy Report Database http://www.energy.ca.gov/almanac/electricity_data/web_qfer/Heat_Rates.php

Figure 17
2015 SCE Natural Gas Resource Heat Rates and Net Generation [41] [42]

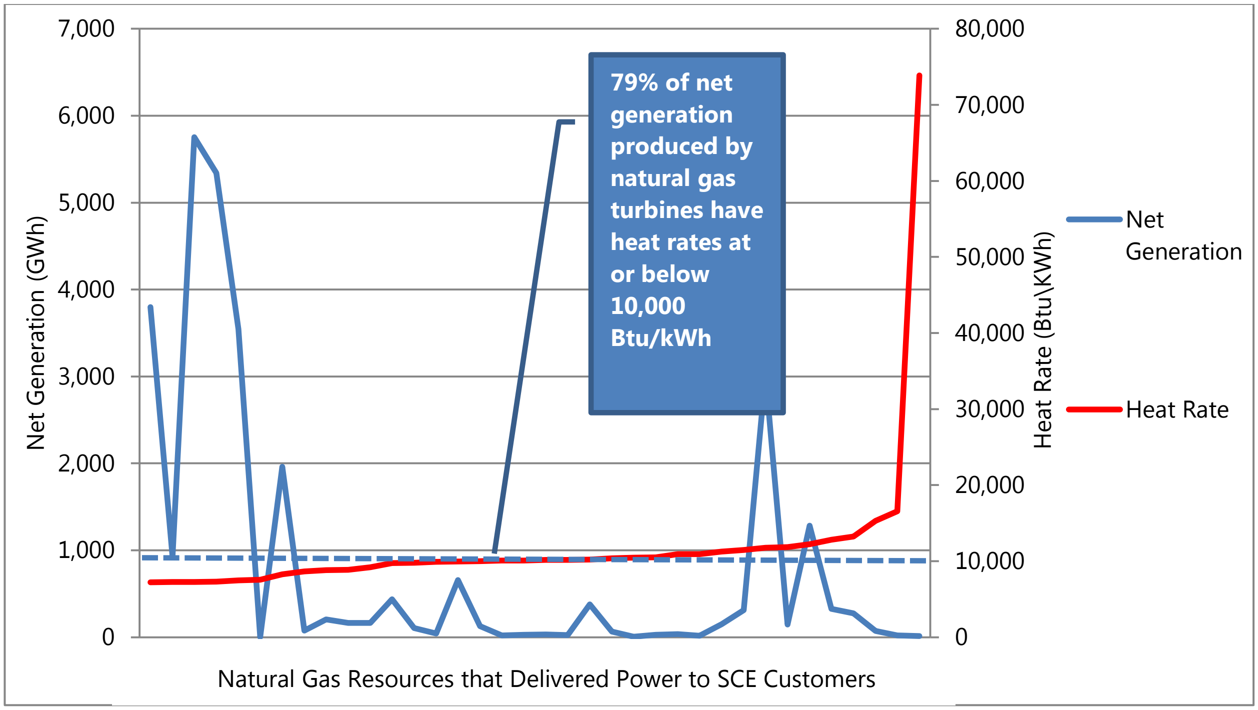
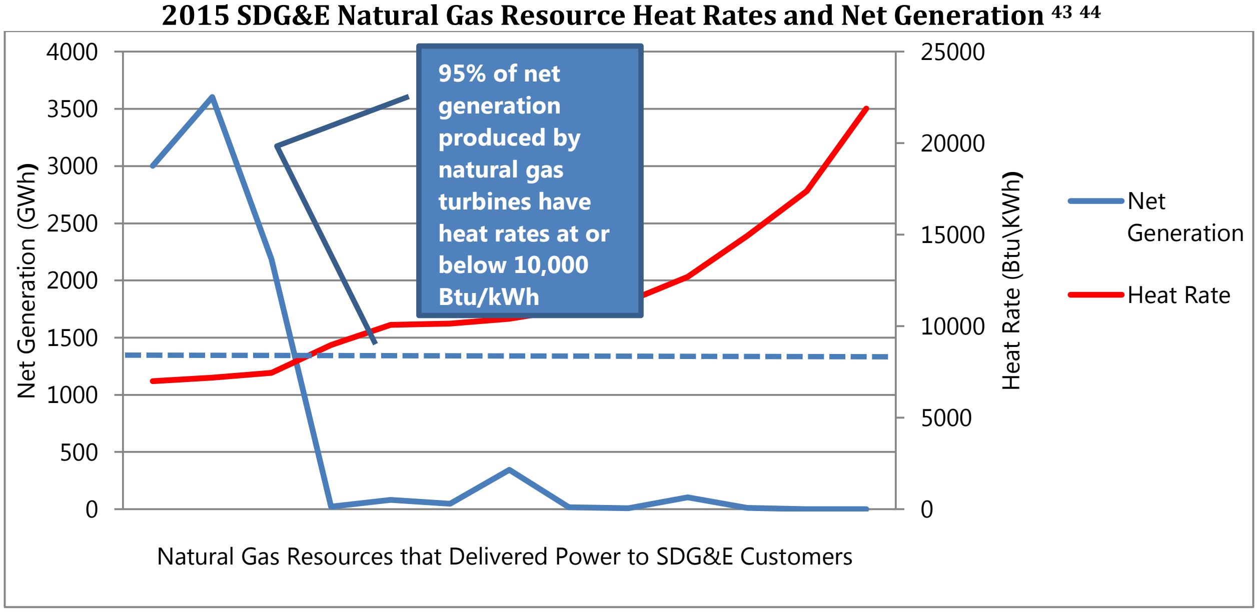


Figure 18
2015 SDG&E Natural Gas Resource Heat Rates and Net Generation [43] [44]

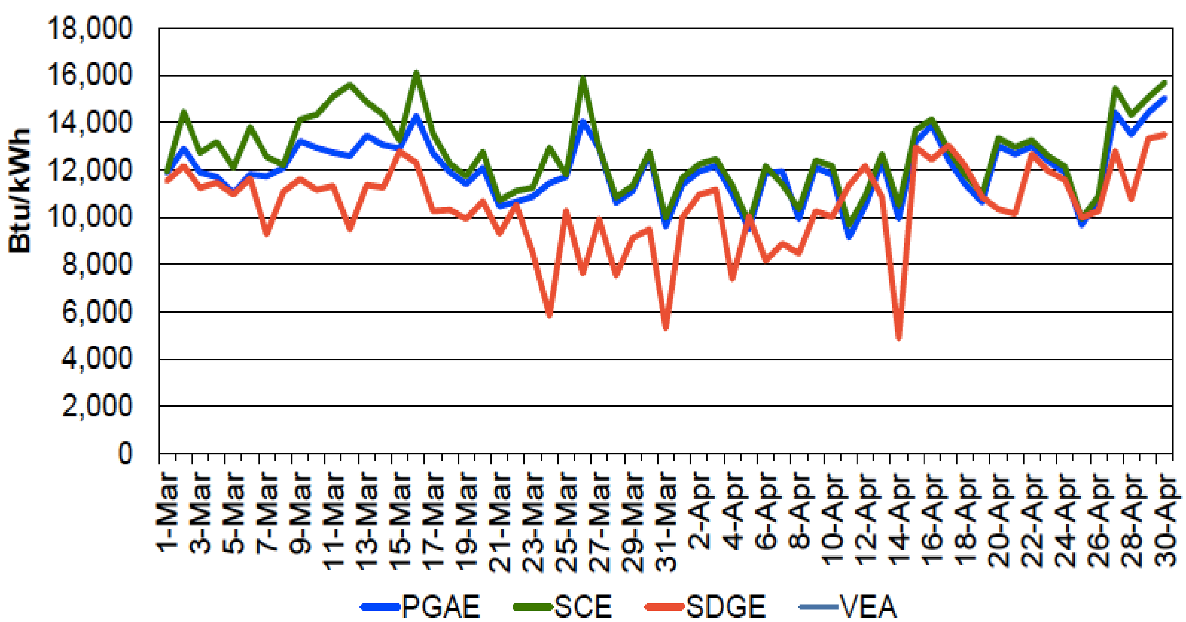


[41] This data includes net generation and heat rates from natural gas generation resources, including SCE owned and third-party resources that supply purchased power.
[42] Data obtained from SCE Form 1 and California Energy Commission, Quarterly Fuel and Energy Report Database http://www.energy.ca.gov/almanac/electricity_data/web_qfer/Heat_Rates.php
[43] This data includes net generation and heat rates from natural gas generation resources, including SDG&E owned and third-party resources that supply purchased power.
[44] Data obtained from SDG&E Form 1 and California Energy Commission, Quarterly Fuel and Energy Report Database http://www.energy.ca.gov/almanac/electricity_data/web_qfer/Heat_Rates.php

A more accurate depiction of the efficiency of generation that is dispatched to the grid is the market implied heat rate (MIHR).[45] Since the MIHR is adjusted for the price of natural gas, which can fluctuate on a day-to-day basis, it establishes an economic benchmark for generation bids into the wholesale electric market. If the heat rate for a generation resource is below the MIHR it is economically feasible to offer a bid for electricity supplied by that resource. If the heat rate is below the MIHR then it is likely that that a bid will not be submitted.

Figures 19 and 20 respectively depict the March-April 2016 and August-September 2016 CAISO daily integrated forward market (IFM) MIHR at default load aggregations points (DLAP) or pricing nodes. During March-April 2015 the MIHR ranged between 6,000 and 16,000 Btu/kWh while the MIHR ranged between roughly 12,000 and just below 20,000 Btu/kWh from August-September 2015. As expected, the MIHR has a higher range during summer peak load conditions. Given that the MIHR is an economic benchmark for submitting generation bids into the wholesale electricity market, most of the resources depicted in Figures 18-20, those that have heat rates at or below 15,000 Btu/kWh, would have an incentive to participate.

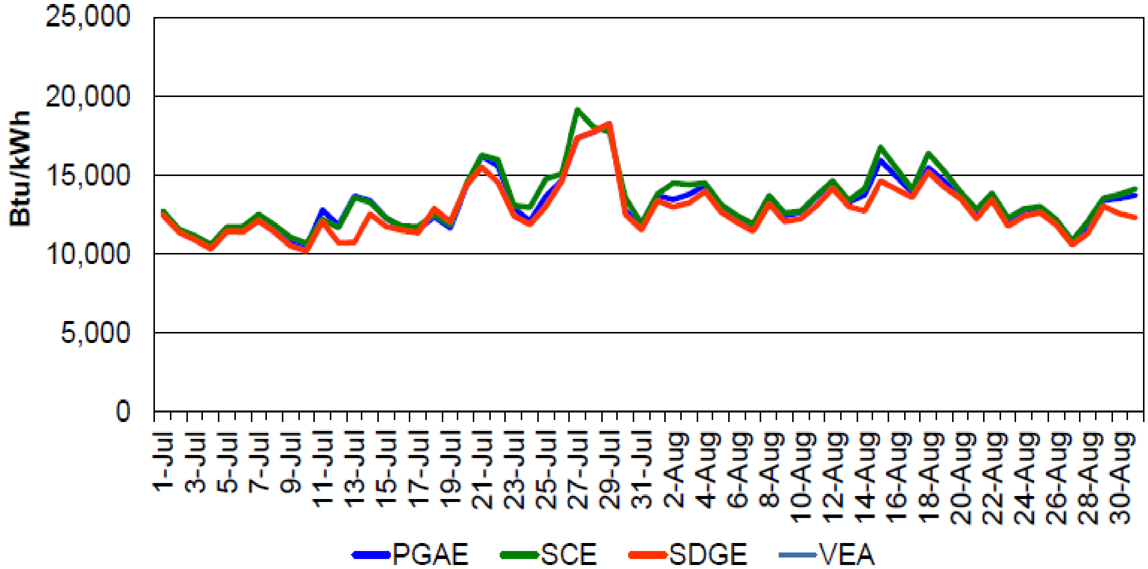
Figure 19
Daily IFM Default LAP Market Implied Heat Rate (March-April 2016)[46]



[45] According to the Energy Information Administration (EIA) The implied heat rate is "a calculation of the day-ahead electric price divided by the day-ahead natural gas price. Implied heat rate is also known as the 'break-even natural gas market heat rate,' because only a natural gas generator with an operating heat rate (measure of unit efficiency) below the implied heat rate value can make money by burning natural gas to generate power. Natural gas plants with a higher operating heat rate cannot make money at the prevailing electricity and natural gas prices.

[46] CAISO Market Performance Metric Catalog, March 2016, Version 1.31

Figure 20
Daily IFM Default LAP Market Implied Heat Rate (August-September 2016)[47]



[47] CAISO Market Performance Metric Catalog, March 2016, Version 1.31